Sandra L. Hochstetter
Chairman
(501) 682-1455

Daryl E. Bassett
Commissioner
(501) 682-1453

Randy Bynum
Commissioner
(501) 682-1451

ARKANSAS
PUBLIC SERVICE COMMISSION
1000 Center
P.O. Box 400
Little Rock, Arkansas 72203-0400
http://www.Arkansas.gov/psc

Energy Policy Act of 2005, Section 1234
Economic Dispatch Study

Questions for Stakeholders
Responses of the Arkansas Public Service Commission

1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

RESPONSE: In the State of Arkansas, electric service, including the generation component, is primarily provided by either the investor-owned, vertically integrated electric utilities, or by the Arkansas Electric Cooperative Corporation (AECC) and its members. The investor-owned utilities provide most of the generation dispatch in the State of Arkansas. Most of the state's service territory is served either by Entergy Arkansas or AECC and its members. Entergy Corporation performs the dispatching service for Entergy Arkansas and for AECC within the State of Arkansas. Note that Entergy operates and performs a joint central dispatch for Entergy Louisiana, Entergy New Orleans, Entergy Mississippi, and Entergy Gulf States (in both Texas and Louisiana), and AECC. SWEPCO's dispatch is done by American Electric Power-West, and OG&E's is done by OGE.

Even though SWEPCO and OG&E are members of the Southwest Power Pool (SPP), their applications to become members of the SPP RTO have not yet been approved by the relevant state commissions, including the Arkansas Commission, so these utilities are still required to provide their own economic dispatch and that function remains state-jurisdictional. Moreover, since SPP's proposed energy imbalance market is still in the developmental stages, and in any event will be a voluntary market, there is no centralized dispatch being provided by SPP. Regardless of any subsequent RTO membership approvals, a state regulatory decision to allow the state-jurisdictional function of economic dispatch to be shifted away from the generation-owning utility to a different entity could not occur without specific regulatory approval and the appropriate cost-effective and net public interest determinations.

2) Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

RESPONSE: The Act's definition of economic dispatch needs revision. It should define economic dispatch as the prioritization, from least cost to highest cost, of the operation of generation facilities to produce energy at the lowest overall cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities. The optimal combination of transmission and generation facilities should result in the lowest costs to customers. It is important to remember that the economic dispatch is dependent upon prior decisions concerning transmission upgrades and expansions. Those decisions must be done in the context of a regulatory regime that encourages an economically efficient configuration of generation and transmission to be built. This necessitates that all players in the market appropriately pay their own costs, with no subsidies for transmission upgrades through socialization.

The economic dispatch should be done over an actual or economic trading territory. Other factors that should be considered in economic dispatch are: (1) Issues associated with the unit commitment problem such as ramp rates, minimum loads, maximum loads, minimum down times, reliability must-run, etc; (2) Recognition of the need to evaluate any transmission constraints and RMR issues; (3) Determination of the economics of removing congestion or physical barriers to determine what an optimal economic dispatch would look like; and (4) Greater transparency in the determination of available flowgate capacity.

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

RESPONSE: Currently, non-utility generation is not integrated seamlessly with utility generation. Most purchases of power are "block" purchases or QFs and are, thus, not dispatchable. That may change over time as SPP matures and as the Entergy ICT and Weekly Procurement Process mature, such that non-utility generators are better integrated with utility generation for dispatching purposes. Actual operational practices do not differ from the formal procedures under Arkansas state tariffs and rules, nor do they differ from the economic dispatch definition given. It is expected that as these non-utility generators are better integrated there will be significant benefits to retail electricity users. This is premised on the assumption that those Interconnection and Network Upgrade costs caused by non-utility generators are borne by those generators and not socialized and borne by retail ratepayers.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

RESPONSE: The following changes in economic dispatch procedures would lead to more non-utility generator dispatch: (1) Identification of transmission congestion that is economic to remove; (2) More transparency in determination of available flowgate capacity on the transmission system; (3) Greater exchange of information concerning basic unit commitment engineering data between non-utility generators and the central dispatcher. This requires some degree of independence by the central dispatcher in order to protect proprietary data.

Additionally, this transparency and availability of information and data can be enhanced by an independent entity that performs analysis of transmission congestion, economic upgrades, economic expansions, and economically beneficial trading radius. That information can be used by a state Commission to require, under its state prudence statutes, the appropriate degree of grid enhancements or operational changes necessary to effectuate economic dispatch. State Commissions have prudence authority under a variety of regulatory mechanisms such as fuel cost flowthroughs, rules, etc. State Commissions simply need better information so as to better effectuate economic dispatch; no shift in jurisdiction from state Commissions to the Federal Energy Regulatory Commission is either necessary or appropriate, particularly in the context of a state or region that has retained the traditional regulatory framework of vertically integrated utilities being fully rate regulated and service regulated. Economic dispatch effects generation assets and generation costs, which comprise at least 2/3 of the retail ratepayer's bill, all of which are state-jurisdictional and rate regulated by the state regulatory commission in states such as Arkansas.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to us.

RESPONSE: Greater economic dispatch because of greater use of non-utility generation should decrease overall costs, if the combination of transmission and generation used is the most economic result for ratepayers. Further, if non-utility generation providers understand their proper cost responsibilities in their decision-making, and if the transmission pricing regime is based on a “cost-causers pay” grid, congestion should be relieved over time. It is unclear at this time what the effects will be on portfolio mix and environmental emissions.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

<u>RESPONSE</u>: There should be no reliability impacts as long as new market entrants/bidders into the dispatch process have paid the price for adequate transmission upgrades and expansions to accommodate their incremental flows.